DUKE ENERGY.
PROGRESS

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May 8, 2014

VIA ELECTRONIC FILING AND OVERNIGHT DELIVERY

Jocelyn G. Boyd
Chief Clerk & Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29211

RE: Duke Energy Progress, Inc. Annual Review of Base Rates for Fuel Costs
Docket No. 2014-1-E

Dear Mrs. Boyd:

Enclosed for filing on behalf of Duke Energy Progress, Inc. ("DEP"), please find the following pre-filed Direct Testimony:

1. Kenneth D. Church
2. T. Preston Gillespie, Jr.
3. Sasha J. Weintraub
4. Kimberly D. McGee, and
5. Joseph A. Miller, Jr.

Mr. Gillespie's confidential exhibit 3 is being sent via overnight delivery to your office for filing under seal. The exhibit contains confidential, proprietary, and sensitive outage information that if disclosed, could negatively impact DEP's ability to safely and reliably provide effective service to its customers. Pursuant to Order No. 2005-226, DEP requests that Mr. Gillespie's confidential testimony exhibit 3 be treated and maintained as confidential. We respectfully request that the Commission grant the request for confidential treatment pursuant to 26 S.C. Regs. 103-804(S)(2) and under the Freedom of Information Act, S.C. Code Ann. § 30-4-10 *et seq.* Mr. Gillespie's testimony, with confidential exhibit 3, is being provided to the Office of Regulatory Staff and those parties who signed a confidentiality agreement in the above referenced proceeding.

If you have any questions, please let me know.

Sincerely,

Timika Shafeek-Horton

Timika Shafeek-Horton
Deputy General Counsel

TSH/bml

Enclosures

cc: Brian L. Franklin, Esq.
Jeffrey M. Nelson, Esq., ORS (w/ enclosures)
Robert R. Smith, II, Esq. (w/ enclosures)
Michael K. Lavanga, Esq. (w/ enclosures)
Garret A. Stone, Esq. (w/ enclosures)

BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

Docket No. 2014-1-E

This is to certify that a copy of Duke Energy Progress, Inc.'s pre-filed **Direct Testimony of T. Preston Gillespie, Jr., Kenneth D. Church, Sasha J. Weintraub, Kimberly D. McGee, and Joseph A. Miller, Jr.** in the foregoing docket, has been served by electronic mail or by depositing a copy in the United States Mail, first class postage prepaid, properly addressed to:

Jeffrey M. Nelson, Esq.
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201

Robert R. Smith, II, Esq.
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8th Floor, West Tower
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Washington, DC 20007

This the 8th day of May, 2014.

Timika Shafeek-Horton

Timika Shafeek-Horton
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BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2014-1-E

In the Matter of	)	
Annual Review of Base Rates	)	**DIRECT TESTIMONY OF**
For Fuel Costs for	)	**KENNETH D. CHURCH FOR**
Duke Energy Progress, Inc.	)	**DUKE ENERGY PROGRESS, INC.**
	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kenneth D. Church and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of Nuclear Fuel Engineering's Fuel Management & Design for Duke Energy Progress, Inc. ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEP?

A. I am responsible for nuclear fuel procurement and spent fuel management, as well as the fuel mechanical and thermal hydraulic design and reload licensing analysis for the nuclear units owned and operated by DEP and DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Science degree in mechanical engineering. I began my career with DEC in 1991 as an engineer and worked in various roles, including nuclear fuel assembly and control component design, fuel performance, and fuel reload engineering. I assumed the commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services at DEC in 2001. Beginning in 2011, I incrementally assumed responsibility at DEC for spent nuclear fuel management along with the nuclear fuel mechanical and thermal hydraulic design and reload licensing analysis functions. Subsequently, I assumed the same responsibilities for DEP following the merger between Duke Energy Corporation and Progress Energy, Inc.

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use, and I am currently a registered professional engineer in the state of North Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) provide information regarding DEP's nuclear fuel purchasing practices, (2) provide costs for the March 1, 2013 through February 28, 2014 review period ("review period"), and (3) describe changes forthcoming for the July 1, 2014 through June 30, 2015 billing period ("billing period").

Q. YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Church Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Church Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. PLEASE DESCRIBE THE COMPONENTS THAT MAKE UP NUCLEAR FUEL.

A. In order to prepare uranium for use in a nuclear reactor, it must be processed from an ore to a ceramic fuel pellet. This process is commonly broken into four distinct industrial stages: (1) mining and milling, (2) conversion, (3) enrichment, and (4) fabrication. This process is illustrated graphically in Church Exhibit 1.

Uranium is often mined by either surface (i.e., open cut) or underground mining techniques, depending on the depth of the ore deposit. The ore is then sent to a mill where it is crushed and ground-up before the uranium is extracted by leaching, the process in which either a strong acid or alkaline solution is used to dissolve the uranium. Once dried, the uranium oxide ("U_3O_8") concentrate – often referred to as yellowcake – is packed in drums for transport to a conversion facility. Alternatively, uranium may be mined by in situ leach ("ISL") in which oxygenated groundwater is circulated through a very porous ore body to dissolve the uranium and bring it to the surface. ISL may also use slightly acidic or alkaline solutions to keep the uranium in solution. The uranium is then recovered from the solution in a mill to produce U_3O_8.

After milling, the U_3O_8 must be chemically converted into uranium hexafluoride ("UF_6"). This intermediate stage is known as conversion and produces the feedstock required in the isotopic separation process.

Naturally occurring uranium primarily consists of two isotopes, 0.7% Uranium-235 ("U-235") and 99.3% Uranium-238 ("U-238"). Most of this country's nuclear reactors (including those of the Company) require U-235 concentrations in the 3-5% range to operate a complete cycle of 18 to 24 months between refueling outages. The process of increasing the concentration of U-235 is known as enrichment. Gas centrifuge is the primary technology used by the commercial enrichment suppliers. This process first applies heat to the UF_6 to create a gas, then, using the mass differences between the uranium isotopes, the natural uranium is separated into two gas streams, one being enriched to the desired level of U-235, known as low enriched uranium, and the other being depleted in U-235, known as tails.

Once the UF_6 is enriched to the desired level, it is converted to uranium dioxide ("UO_2") powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Church Exhibit 2, DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments.

For uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. Throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEP's exposure to price volatility. Diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. WHAT CHANGES HAVE OCCURRED IN THE UNIT COST OF THE VARIOUS STAGES OF NUCLEAR FUEL DURING THE REVIEW PERIOD?

A. During the review period, the published long-term market price for uranium concentrates was in the range of $50.00/lb to $57.00/lb. During this same period, the published spot market price, which is referenced in a segment of long-term contracts in order to establish delivery price, ranged from a low of $34.00/lb to a high of $42.25/lb. DEP mitigates the impact of spot market volatility on the portfolio of supply contracts by using a mixture of pricing mechanisms. DEP's portfolio of diversified contract pricing yielded an average unit cost of $48.97/lb for uranium concentrates during the review period.

The decrease in market price for uranium concentrates during the review period was primarily due to reduced demand following the Fukushima event in March 2011. Consistent with its portfolio approach to contracting, DEP entered into several long-term contracts during this period. Industry consultants, however, believe market prices need to increase from current levels in order to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

During the review period, the published long-term market price for enrichment services was in the range of $107.00/Separative Work Unit ("SWU") to

$134.00/SWU. As in the uranium market, the decline in long-term market price for enrichment services was primarily due to reduced demand following the Fukushima event. The transition by enrichment suppliers from gaseous diffusion technology to the more cost efficient gas centrifuge technology was also influential. The average unit cost of DEP's purchases of enrichment services during the review period was $127.57/SWU. One hundred percent of DEP's enrichment purchases during the review period were delivered under long-term contracts negotiated at market prices prior to the review period. This included long-term contracts negotiated when market prices had increased due to growing demand from the onset of the nuclear renaissance. As described earlier in my testimony, however, staggering long-term contracts over time for these components of the nuclear fuel cycle means DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. This approach has the effect of smoothing out DEP's exposure to price volatility.

Long-term prices for fabrication services generally trended upward during the review period. For conversion services, long-term market prices remained relatively stable, but spot market prices trended downward. These costs, however, have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 13% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which are 48% and 34%, respectively.

Q. PLEASE DESCRIBE THE RECENT DECISION OF THE D.C. CIRCUIT COURT OF APPEALS REGARDING THE COLLECTION OF HIGH LEVEL WASTE FEES BY THE DEPARTMENT OF ENERGY PURSUANT TO THE NUCLEAR WASTE POLICY ACT.

A. On November 19, 2013, the D.C. Circuit Court of Appeals issued a decision against the U.S. Department of Energy ("DOE") in *Nat'l Ass'n of Regulatory Utility Com'rs v. Dep't of Energy*, 736 F.3d 517 (D.C. Cir. 2013)("NARUC v. DOE"). I am not an attorney and, therefore, am not giving a legal opinion, but my understanding from reviewing the decision on my own is that the lawsuit challenged the DOE's continued collection of the one-tenth of a cent per kilowatt-hour fee imposed by the Nuclear Waste Policy Act ("NWPA") to pay for used fuel management and disposal. My understanding is that the court in *NARUC v. DOE* required DOE to "submit to Congress a proposal to change the fee to zero until such a time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan."

Q. HOW WILL THIS DECISION IMPACT DEP'S NUCLEAR FUEL COST?

A. Under the NWPA, the fee remains in effect until DOE acts to propose the fee adjustment to Congress, and the proposal has been before Congress for a minimum of 90 days. Until that time, utilities continue to be obligated to make quarterly Nuclear Waste Fund payments. At the current time, there is a high confidence that there will be a change to the fee collection. Company witness McGee has proposed a fuel and fuel-related factor which reflects the discontinuance of the payment during the billing period. I will note, however, that the suspension of the DOE waste fee may be temporary in nature with some likelihood that a nuclear waste fee could be reinstated in the future.

Q. WHAT CHANGES DO YOU SEE IN DEP'S NUCLEAR FUEL COST IN THE BILLING PERIOD?

A. The Company anticipates an increase in nuclear fuel costs on a cents per kWh basis through the next billing period. Because fuel is typically expensed over two to three operating cycles – roughly three to six years – DEP's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the review period, as well as prior periods. A portion of the fuel residing in the reactors during the billing period will have been obtained under historical contracts negotiated in attractive markets. Newer contracts signed prior to recent market decreases, however, reflect increasing price trends, and are now contributing to a portion of the uranium, enrichment, and fabrication costs reflected in the total fuel expense. Also, as discussed earlier in my testimony, DEP is closely following the ultimate legal determination regarding the collection of the nuclear waste fee.

The average fuel expense, assuming DEP is able to cease collection of the nuclear waste fee, is expected to decrease from 0.716 cents per kilowatt hour ("kWh") incurred in the review period, to approximately 0.639 cents per kWh in the billing period. This change does reflect the discharge of fuel with a lower cost basis from the reactor and its replacement with fuel procured under new contracts negotiated in higher markets, but decreases due to removal of the DOE waste fee.

Q. WHAT STEPS IS DEP TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

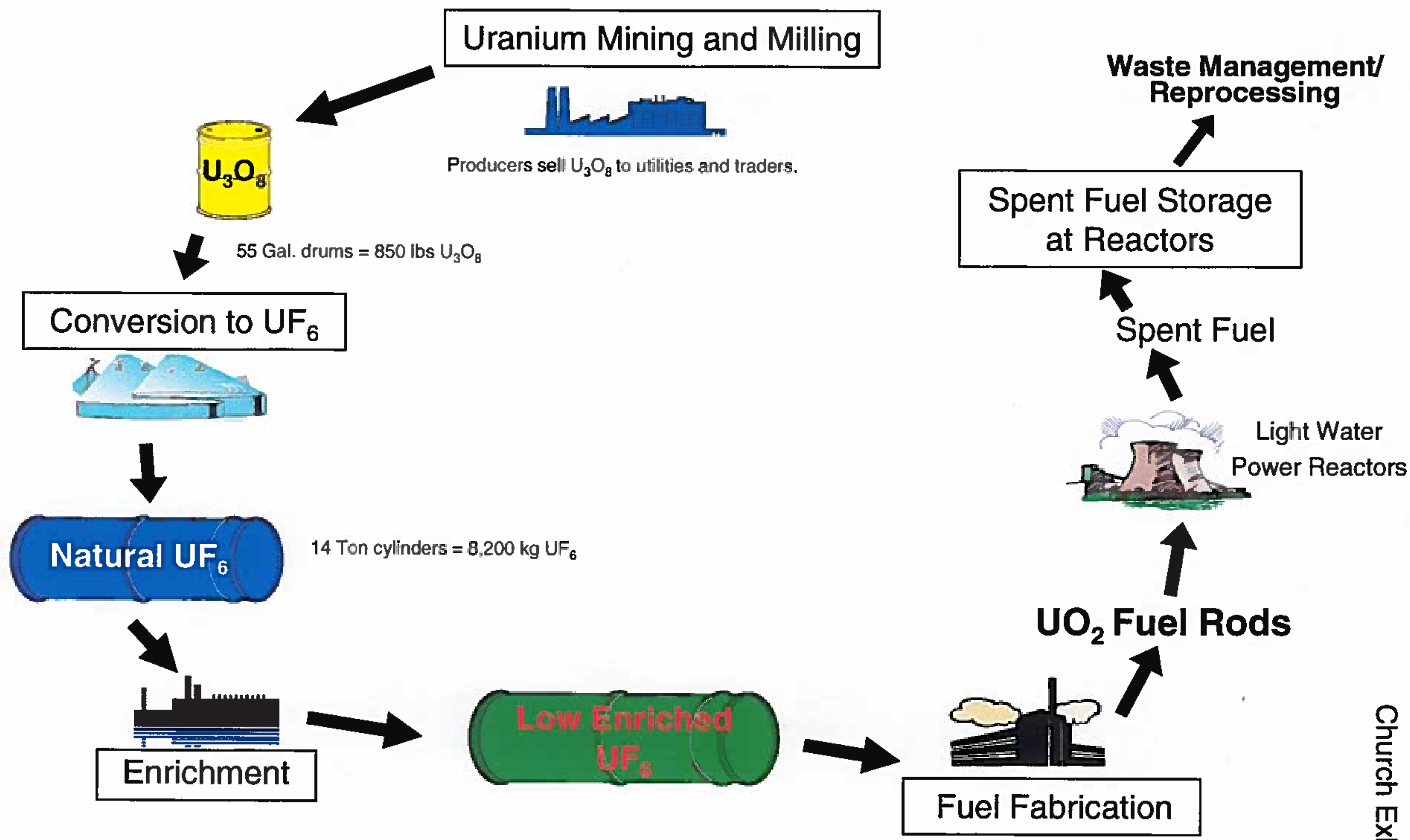
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEP's exposure to price volatility.

Although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a cents per kWh basis will likely continue to be a fraction of the cents per kWh cost of fossil fuel. Therefore, customers will continue to benefit from DEP's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

The Nuclear Fuel Cycle



Church Exhibit 1

Church Exhibit 2

Duke Energy Progress Nuclear Fuel Procurement Practices

The Company's nuclear fuel procurement practices are summarized below.

- Near and long-term consumption forecasts are computed based on factors such as: nuclear system operational projections given fleet outage/maintenance schedules, adequate fuel cycle design margins to key safety licensing limitations, and economic tradeoffs between required volumes of uranium and enrichment necessary to produce the required volume of enriched uranium.
- Nuclear system inventory targets are determined and designed to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving market conditions. Inventories are monitored on an ongoing basis.
- On an ongoing basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- Qualified suppliers are invited to make proposals to satisfy additional or future contract needs.
- Contracts are awarded based on the most attractive evaluated offer, considering factors such as price, reliability, flexibility and supply source diversification/portfolio security of supply.
- For uranium concentrates, conversion and enrichment services, long term supply contracts are relied upon to fulfill the largest portion of forward requirements. By staggering long-term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Due to the technical complexities of changing suppliers, fabrication services are generally sourced to a single domestic supplier on a plant-by-plant basis using multi-year contracts.
- Spot market opportunities are evaluated from time to time to supplement long-term contract supplies as appropriate based on comparison to other supply options.
- Delivered volumes of nuclear fuel products and services are monitored against contract commitments. The quality and volume of deliveries are confirmed by the delivery facility to which Duke Energy Progress has instructed delivery. Payments for such delivered volumes are made after Duke Energy Progress' receipt of such delivery facility confirmations.

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2014-1-E

In the Matter of	)	
Annual Review of Base Rates	)	**DIRECT TESTIMONY OF**
for Fuel Costs for	)	**SASHA J. WEINTRAUB FOR**
Duke Energy Progress, Inc.	)	**DUKE ENERGY PROGRESS, INC.**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alexander ("Sasha") J. Weintraub. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity I am responsible for the procurement of fossil fuels and environmental reagents for the Duke Energy Progress, Inc. ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC")(collectively, the "Companies") generation fleet, as well as for the generation fleets of the other Duke Energy regulated utilities. I am also responsible for portfolio management and short term power trading for Duke Energy, and am responsible for the fossil fuel price forecasts used for fuel filings and resource planning purposes for all of Duke Energy's regulated utility subsidiaries, including DEP.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Engineering from Rensselaer Polytechnic Institute, a Master's in Mechanical Engineering from Columbia University, and a Ph.D. in Industrial Engineering from North Carolina State University. From February 2003 until June 2005, I was Director of Coal Marketing and Trading for Progress Fuel Corporation, a former subsidiary of Progress Energy, Inc. ("Progress Energy"). Subsequently, I was Director of Coal for DEP and Duke Energy Florida, Inc. ("DEF"), and before assuming my current position, I was Vice President - Fuels and Power Optimization for DEP and DEF.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the Public Service Commission of South Carolina in DEP's 2013 annual fuel proceeding in Docket No. 2013-1-E, as well as in DEC's 2013 annual fuel proceeding in Docket No. 2013-3-E. I also testified before this Commission in Docket No. 2011-158-E, and I have testified on multiple occasions on behalf of Duke Energy in proceedings before this and other state commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide fossil fuel costs for the period March 1, 2013 through February 28, 2014 ("review period"), and describe changes forthcoming for the period July 1, 2014 through June 30, 2015 ("billing period"). I also provide an update from a procurement and operations perspective on the Joint Dispatch Agreement ("JDA") that – pursuant to the merger agreement between Duke Energy and Progress Energy ("Merger") – Duke Energy is using to deliver savings to its North Carolina and South Carolina customers, as well as fuel savings that DEP has realized to date on behalf of its customers as a result of the Merger.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS TO YOUR TESTIMONY.

A. Weintraub Exhibit 1 summarizes the Company's Fossil Fuel Procurement Practices, and Weintraub Exhibit 2 summarizes monthly contract and spot coal purchases during the review period and the period of March 1, 2012 through February 28, 2013 ("prior review period").

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes, they were prepared at my direction.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of the Company's fossil fuel procurement practices is set out in Weintraub Exhibit 1.

Q. PLEASE DESCRIBE DEP'S DELIVERED COST OF COAL DURING THE REVIEW PERIOD.

A. The Company's average delivered coal cost per ton decreased less than 1.0% from $90.74 per ton from the prior review period to $90.31 per ton in the review period. The average transportation costs increased approximately 16%, from $27.38 per ton in the prior review period to $31.83 per ton in the review period. The increase in transportation costs reflects DEP's ability to use lower cost coals from non-Central Appalachian regions, thereby lowering the overall delivered cost of coal.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL MARKET CONDITIONS.

A. Coal markets continue to be in a state of flux due to a number of factors, including: (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which lower total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2)

softening demand in global markets for both steam and metallurgical coal; (3) increased prices and volatility for gas due to adverse winter weather; (4) continued increase in gas supply combined with installation of new combined cycle ("CC") generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (5) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity.

Q. HOW DO YOU EXPECT THESE TRENDS TO AFFECT DEP'S COAL BURN AND INVENTORY LEVELS?

A. Due to the increasing competitiveness for low cost electricity between natural gas and coal, it is anticipated that DEP's coal generation will fluctuate with prevailing market conditions. With the increase in natural gas prices in response to extreme weather, DEP's actual coal burn for the review period was 7.6 million tons, which is more than 40% higher than the 5.4 million tons originally anticipated in the currently billed rate. The projected coal burn reflected in the rate proposed for the billing period is 6.4 million tons. DEP's billing period projections for coal generation, however, may be impacted due to changes in natural gas prices, volatile power prices, and demand. Although inventory levels were below target at the end of the review period as a result of much stronger than expected coal burns due to severe winter weather and lower than expected receipts of coal, DEP has returned to near target inventory levels as of the end of April 2014. Future inventory levels are dependent on actual versus projected coal burns and actual coal deliveries based on performance of the railroads.

Q. WHAT IS THE PROJECTED AVERAGE DELIVERED COAL COST FOR THE BILLING PERIOD?

A. Combining coal and transportation costs, the Company projects average delivered coal costs of approximately $89.88 per ton for the billing period. This represents a slight decrease from the review period actual cost. This projected cost, however, is subject to change based on (1) changes in oil prices, which impact transportation rates; (2) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts; (3) performance of contract deliveries by suppliers and railroads which may not occur despite the Company's strong contract compliance monitoring process; (4) the amount of non-Central Appalachian coal the Company is able to consume: and (5) the market prices for DEP's open coal positions that are prevalent at the time of purchase.

Q. WHAT STEPS IS DEP TAKING TO CONTROL COAL COSTS?

A. The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing contract extension options that provide flexibility to extend terms within a particular price band.

The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Q. PLEASE DESCRIBE DEP'S PROCUREMENT PRACTICES FOR NATURAL GAS.

A. The Company's in-house personnel are responsible for natural gas contracting, competitive procurement, scheduling, and balancing efforts for the gas generation fleet. The Company has implemented gas procurement practices that include periodic Request for Proposals ("RFPs"), market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports DEP's combustion turbine ("CT") and CC facilities.

Lastly, as described in previous testimony filed in Docket No. 2013-1-E, in December 2012 the Company received approval for the Asset Management and Delivered Supply Agreement ("AMA") between DEP and DEC, which was implemented on January 1, 2013. In the AMA, DEC is the designated Asset Manager that procures and manages the combined gas supply needs for DEC and DEP, and performs the necessary scheduling and balancing on the pipelines.

Q. HOW IS NATURAL GAS DELIVERED TO DEP'S GENERATING FACILITIES?

A. The Company procures long-term firm transportation that provides natural gas to its generating facilities. In addition, as needed, DEP may procure delivered supply, shorter-term firm pipeline capacity through the capacity release market, and have market supply options that provide the needed natural gas supply to its generating facilities.

Q. DOES DEP MAINTAIN AN INVENTORY OF NATURAL GAS?

A. The Company has a storage agreement as part of the AMA. As the Asset Manager, DEC will procure all the needed supply for the combined Carolinas gas needs and as part of that agreement, will have access to the released storage agreement. On any given day, DEC may utilize the storage to balance and support the Carolinas gas needs.

Q. WHAT CHANGES IN VOLUME DOES THE COMPANY ANTICIPATE WITH NATURAL GAS CONSUMPTION?

A. The Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 119 billion cubic feet ("Bcf") of natural gas in the review period, compared to approximately 89 Bcf in the prior review period. This increase was driven by the addition of new Lee CC generation at the end of 2012. In addition, DEP's Sutton CC went into service in the latter part of 2013. For the billing period, DEP's current forecasted natural gas consumption is approximately 131Bcf. The forecasted increase in natural gas consumption includes a full year of generation from Sutton CC.

Q. PLEASE DESCRIBE THE CURRENT STATE OF THE NATURAL GAS MARKET, INCLUDING THE NATURAL GAS PRICES EXPERIENCED DURING THE REVIEW PERIOD.

A. The development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, forward natural gas prices continue to remain at lower levels. With respect to natural gas prices experienced during the recent Polar Vortex, extreme weather and higher than normal natural gas demand resulted in DEP experiencing much higher spot natural gas prices during January and February 2014 than it experienced in previous review periods. The Company's average price of gas purchased for the review period was $6.10 per Million British Thermal Units ("MMBtu"), compared to $5.03 per MMBtu during the prior review period.

Q. **PLEASE DESCRIBE THE OUTLOOK FOR THE NATURAL GAS MARKET, INCLUDING THE EXPECTED NATURAL GAS PRICE TREND FOR THE BILLING PERIOD.**

A. New production from shale gas has contributed to substantial increases in the supply of U.S. marketed natural gas. This increase has outstripped demand growth. The Company expects the shale gas production percentage of total natural gas domestic production to continue to increase over time. The current forward prices for natural gas reflect this continued increase in competitively priced supply with an average delivered price of $4.15 per MMBtu through the billing period.

Q. **IN LIGHT OF DEP'S INCREASED USAGE OF NATURAL GAS, WHAT IS DEP DOING TO MITIGATE THE EFFECTS THAT INCREASING NATURAL GAS PRICES COULD HAVE ON FUEL COSTS?**

A. The Company has been executing a natural gas hedging strategy for the last several years in order to mitigate the price volatility of natural gas. The strategy incorporates a "dollar-cost averaging" approach of hedging that financially "locks-in" natural gas prices at a fixed price over time for a percentage of forecasted natural gas burns. DEP will continue to monitor and make adjustments as necessary to its natural gas hedging program.

Q. PLEASE EXPLAIN THE JDA BETWEEN DEP AND DEC.

A. As explained in my previous testimony filed in Docket No. 2013-1-E, the JDA is an agreement between DEP and DEC where DEC acts as the Joint Dispatcher for DEP's and DEC's power supply resources. The JDA has allowed DEP's and DEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the joint dispatch process allows DEP and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEP and DEC.

The joint dispatch savings automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy cost attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the

Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost ultimately incurred by DEP and DEC to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

Through March 2014, the combined merger savings from the JDA and the Companies' fuel procurement activities are $274 million. DEP's and DEC's customers are then allocated their share of the combined savings based upon the resource ratios of the combined company. This resource ratio is 38% for DEP and 62% for DEC through March 2014.

Q. HOW DOES THE COMPANY OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Progress, Inc. Fossil Fuel Procurement Practices

Coal

- Near and long-term consumption forecasts are computed based on factors such as: load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, wholesale energy imports and exports.
- Station and system inventory targets are determined and designed to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- All qualified suppliers are invited to make proposals to satisfy any additional or future contract needs.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards. During the review period the Company utilized both destination and/or origin weights and analysis.

Gas

- Near and long-term consumption forecasts are computed based on factors such as load projections, commodity and emission prices, and fleet maintenance and availability schedules.
- Short-term and Long-term Periodic Requests for Proposals and informal market solicitations will be conducted to potential suppliers to procure a cost competitive, secure and reliable natural gas supply over time to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared to forecasted gas usage to ascertain any additional needs.

Fuel Oil

- No. 2 diesel is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All diesel fuel is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory and reliable suppliers who are responsive and can access multiple terminals. Diesel is replaced on an "as needed basis" as called for by station personnel with guidance from fuel procurement staff.

- Formal solicitation for supply is conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended Febuary 2014 & 2013
Tons

Line No.	Month	Contract (Tons)	Spot (Tons)	Total (Tons)
1	March 2013	502,344	0	502,344
2	April	365,100	0	365,100
3	May	428,174	0	428,174
4	June	554,544	0	554,544
5	July	631,953	0	631,953
6	August	735,088	0	735,088
7	September	761,610	0	761,610
8	October	479,841	0	479,841
9	November	592,803	11,701	604,504
10	December	548,247	22,864	571,111
11	January 2014	409,842	23,533	433,375
12	February	272,292	159,621	431,913
13	**Total** (Sum L1:L12)	**6,281,838**	**217,719**	**6,499,557**

Line No.	Month	Contract (Tons)	Spot (Tons)	Total (Tons)
14	March 2012	780,531	12,809	793,340
15	April	595,721	0	595,721
16	May	688,255	0	688,255
17	June	957,296	206	957,502
18	July	759,349	0	759,349
19	August	878,974	2,277	881,250
20	September	826,079	0	826,079
21	October	864,605	0	864,605
22	November	725,227	0	725,227
23	December	890,910	1,217	892,127
24	January 2013	471,048	2,448	473,497
25	February	498,700	491	499,191
26	**Total** (Sum L14:L25)	**8,936,695**	**19,448**	**8,956,143**

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2014-1-E

In the Matter of	)	**DIRECT TESTIMONY OF**
Annual Review of Base Rates	)	**T. PRESTON GILLESPIE, JR. FOR**
for Fuel Costs for	)	**DUKE ENERGY PROGRESS, INC.**
Duke Energy Progress, Inc.	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is T. Preston Gillespie, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Vice President of Nuclear Operations for Duke Energy Carolinas, LLC ("DEC"). I have executive accountability for DEC's Oconee Nuclear Station ("Oconee") in Seneca, South Carolina, and Duke Energy Progress, Inc.'s ("DEP" or the "Company") Robinson Nuclear Generating Station ("Robinson") near Hartsville, South Carolina.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF NUCLEAR OPERATIONS FOR OCONEE AND ROBINSON?

A. As Senior Vice President of Nuclear Operations for Oconee and Robinson, I am responsible for providing executive oversight for the safe and reliable operation of those nuclear stations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Mechanical Engineering from Clemson University. I am a registered professional engineer in South Carolina, and held a senior operator license from the U.S. Nuclear Regulatory Commission ("NRC"). I began my career with DEC (formerly known as Duke Power Company) in 1986 as an assistant engineer at Oconee. Since that time, I have held various roles of increasing responsibility in engineering, work management, and operations, including operations shift manager, and nuclear engineering manager in 2004 responsible for managing the nuclear and electrical engineering activities at Oconee. I was named operations manager at Catawba Nuclear Station in 2007, and in 2008 I became plant manager at Oconee, transitioning to site vice president in September 2010. I assumed my current role in March 2013.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the Public Service Commission of South Carolina in DEP's 2013 annual fuel proceeding in Docket No. 2013-1-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and discuss the performance of Brunswick Nuclear Station ("Brunswick"), Shearon Harris Nuclear Station ("Harris"), and Robinson for the period of March 1, 2013 through February 28, 2014 (the "review period").

Q. YOUR TESTIMONY INCLUDES THREE EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS.

A. The exhibits and descriptions are as follows:

Gillespie Exhibit 1 - Calculation of the nuclear capacity factor for the review period pursuant to § 58-27-865 of the Code of

Laws of South Carolina ("S.C. Code Ann." or the "Code")

Gillespie Exhibit 2 - Nuclear outage data for the review period

Gillespie Exhibit 3 - Nuclear outage data for the billing period[1]

Q. PLEASE DESCRIBE DEP'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 3,050 megawatts ("MWs") of generating capacity, made up as follows:

Brunswick -	1,527 MWs [2]
Harris -	778 MWs [3]
Robinson -	741 MWs

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF DEP'S NUCLEAR GENERATION ASSETS.

A. The Company's nuclear fleet consists of three generating stations and a total of four units. Brunswick is a boiling water reactor facility with two units located just north of Southport, North Carolina, and was the first nuclear plant built in North Carolina. Unit 2 began commercial operation in 1975, followed by Unit 1 in 1977. The operating licenses for Brunswick were renewed in 2006 by the NRC, extending operations up to 2036 and 2034 for Units 1 and 2, respectively. Harris, located in New Hill, North Carolina, is a pressurized water reactor that began commercial operation in 1987. The NRC issued a renewed license for Harris in 2008, extending operations up to 2046. Brunswick and Harris are jointly owned with the North Carolina Eastern Municipal Power Agency. Robinson is a single unit pressurized

[1] This data is provided in confidential and publicly redacted versions for security purposes.
[2] Represents DEP's ownership share of 81.67%.
[3] Represents DEP's ownership share of 83.83%.

water reactor located near Hartsville, South Carolina that began commercial operation in 1971. The license renewal for Robinson Unit 2 was issued by the NRC in 2004, extending operation for Robinson up to 2030.

Q. WHAT ARE DEP'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DEP's nuclear generation department is to safely provide reliable and cost-effective electricity to DEP's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with detailed procedures. The Company maintains station equipment and systems reliably, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed, and high quality work activities, which effectively ready the plant for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DEP'S NUCLEAR FLEET DURING THE REVIEW PERIOD.

A. Overall, DEP's nuclear stations operated well during the review period, and supplied 43.7% of the power used by its Carolinas customers. The four nuclear units operated at an actual system average capacity factor of 86.77%, with Brunswick Unit 1 achieving an actual capacity factor of 98.3%. Robinson completed a breaker-to-breaker run of 531 days leading into the fall refueling and maintenance outage that began on September 14, 2013, marking a new record and besting the previous record of 517 days, which was set in 2002.

The Company continues to look for ways to improve the operations of its nuclear fleet, which, as shown on Gillespie Exhibit 1, achieved a net nuclear capacity factor, excluding reasonable outage time pursuant to S.C. Code Ann. § 58-27-865(F), of 102.21% for the review period. This capacity factor is above the 92.5% set forth in this section of the Code, which states in pertinent part:

> There shall be a rebuttable presumption that an electrical utility made every reasonable effort to minimize cost associated with the operation of its nuclear generation facility or system, as applicable, if the utility achieved a net capacity factor of ninety-two and one-half percent or higher during the period under review. The calculation of the net capacity factor shall exclude reasonable outage time associated with reasonable refueling, reasonable maintenance, reasonable repair, and reasonable equipment replacement outages; the reasonable reduced power generation experienced by nuclear units as they approach a refueling outage; the reasonable reduced power generation experienced by nuclear units associated with bringing a unit back to full power after an outage....

The performance results discussed above support DEP's continued commitment for achieving high performance without compromising safety and reliability.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS DEP'S PHILOSOPHY FOR SCHEDULING REFUELING AND MAINTENANCE OUTAGES?

A. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear system. Prior to a planned outage, DEP develops a detailed schedule for the outage and for major tasks to be performed including sub-schedules for particular activities.

The Company's scheduling philosophy is to plan for a best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time an outage task was performed is 10 days, then 10 days or less becomes the goal for that task in each subsequent outage. Those individual goals are incorporated into an overall outage schedule. The Company aggressively works to meet, and measures itself against, that schedule. Further, to minimize potential impacts to outage schedules, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan.

As noted, the schedule is utilized for measuring outage planning and execution, and driving continuous improvement efforts. However, in order to provide reasonable, rather than best ever, total outage time for planning purposes, particularly with the dispatch and system operating center functions, DEP also develops an allocation of outage time which incorporates reasonable schedule losses. The development of each outage allocation is dependent on maintenance and repair activities included in the outage, as well as major projects to be implemented during the outage. Both schedule and allocation are set aggressively to drive continuous improvement in outage planning and execution.

Q. HOW DOES DEP HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. When an outage extension becomes necessary, DEP believes that work completed in the extension results in longer continuous run times and fewer forced outages, thereby reducing fuel costs in the long run. Therefore, if an unanticipated issue that has the potential to become an on-line reliability issue is discovered while a unit is off-line for a scheduled outage and repair cannot be completed within the planned work window, the outage is usually extended to perform necessary maintenance or repairs prior to returning the unit to service. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

Q. DOES DEP PERFORM POST OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. The Nuclear industry recognizes that constant focus on raising standards and excellence in operations results in improved nuclear safety and reliability. As such, DEP applies self-critical analysis to each outage and, using the benefit of hindsight, identifies every potential cause of an outage delay or event resulting in a forced or extended outage, and applies lessons learned to drive continuous improvement. The Company also evaluates the performance of each function and discipline involved in outage planning and execution from the perspective of identifying areas in which it can utilize self-critical observation for improvement efforts. Given this focus on identifying opportunities for improvement, these critiques and cause analyses do not document the broader context of the outage or event, and rarely reflect DEP's strengths and successes.

As an example, the Brunswick Unit 2 alternate decay heat removal ("ADHR") project "lessons learned" significantly benefitted a condensate margin improvement project for Brunswick Unit 1 with respect to piping and support system installation. The extensive use of metrology, prefabrication work, granular resource loaded scheduling, and robust oversight not only contributed to meeting the project schedule, but also contributed to the Brunswick team's success in avoiding adverse impacts to the overall refueling and maintenance outage.

Q. WHAT OUTAGES WERE REQUIRED FOR REFUELING AND MAINTENANCE AT DEP'S NUCLEAR FACILITIES DURING THE REVIEW PERIOD?

A. There were three refueling and maintenance outages during the review period and additional time was required for two of these outages to complete activities needed for on-line reliability. The spring 2013 refueling and maintenance outage on Brunswick Unit 2 was allocated for 55 days and required a 13-day extension, most notably due to installation of the ADHR system, an upgraded replacement to the aging and obsolete vintage system, and emergent replacement of both safety-related transformers. Other major work completed during the Unit 2 outage at Brunswick included replacement of the auxiliary transformer, installation of a drywell camera for on-line leakage monitoring, guide pad repairs on the main steam isolation valves, implementation of a variable frequency drive software upgrade to improve reliability, and completion of 292 flow accelerated corrosion inspections of main steam cross-under piping, as well as a vessel internals inspection. The Company also de-sludged the Torus - which is a pool of water used to suppress or cool the reactor coolant in an accident - to reduce radiation dose and improve safety system suction strainer design margins, and modified the feedwater pump main oil pumps to improve reliability. In total, DEP completed 16,678 activities within this outage.

The refueling and maintenance outage for Robinson began in September 2013. The outage was allocated at 55 days and was completed 2.5 days ahead of that allocation. Both primary and secondary maintenance efforts were completed for the reactor vessel, steam generators, reactor coolant pumps, and heat exchangers along with maintenance activities for the turbine/generator, main feedwater pumps, service water, and condensers. Major activities completed included inspections of the reactor vessel cold leg nozzles and injection valves, bottom mounted instrumentation, core barrel upper and lower girth weld and lower flange, primary bowl cladding, and steam generator dome and upper support plate. Replacements included the reactor coolant pump seal return isolation valve and motor, spray discharge isolations, and the residual heat removal ("RHR") pump motor and seal, along with the RHR heat exchanger outlet bonnet gasket. The Company also completed upgrades for lube oil filtration and seal oil cooler tube bundle for the turbine/generator, and a coupling design upgrade for the main feedwater pump. In total, DEP completed 12,361 refueling and maintenance activities within this outage.

Harris also began a refueling and maintenance outage in the fall of 2013 which was allocated for 26 days and required an extension of 6 days primarily due to repairs prompted by the discovery of a penetration in a reactor head nozzle during inspection. Major work activities during this outage included replacement of the turbine driven auxiliary feedwater control panel, reactor vessel head penetration inspection, check valve inspections, replacement of a safety related cooling coil in containment fan cooler, draining and repair of containment spray additive tank welds, emergency diesel generator ("EDG") governor replacement, and replacement of solid state protection system cards on the B Train. In total, DEP completed 11,399 activities within this outage.

Q. WHAT MEASURES HAS DEP TAKEN TO MAINTAIN THE GOOD PERFORMANCE OF ITS NUCLEAR FLEET?

A. At Brunswick, safety and plant reliability are also a key focus with improvements associated with diesel generator reliability and switchyard reliability. Efforts include installation of a supplemental generator, EDG starting air modifications and fuel oil piping replacement, and transmission insulator replacements. Other recently completed improvements include installation of on-line noble chemistry for Unit 1, which improves radiological safety and reduces worker dose, and flooding mitigation improvements that involved implementation of "Cliff Edge" modifications installing barriers and wave deflectors to address NRC requirements stemming from the Fukushima event in 2011. Brunswick is in the final stages of completing replacement of the fire detection system in the control building, which is on schedule for completion later this year. Turbine building chiller replacement is scheduled to complete in 2015, and governor and voltage regulator replacements for the EDGs will be completed over the next few years.

At Harris, projects are underway to improve reliability, address end-of-life equipment, and perform upgrades required to comply with current industry standards. Recently completed upgrades include structural stiffening of the low pressure turbine supports, non-safety transformer replacements, new heater drain system control components, repair of the reactor vessel head penetrations, and new EDG governors. Ongoing major replacement projects include the "C" air compressor, which is on schedule for completion in July 2014, and start-up transformer cable rerouting with cable replacement completion in June 2014 with old cable removal scheduled for completion in 2015. The Company is also upgrading the start-up transformer oil-filled cable, eliminating the underground cable, and replacing it with overhead cable to meet updated standards and address environmental concerns with age and leakage. In addition, DEP has implemented a breaker and dry type transformer breaker replacement program at Harris, along with the replacement of the fire detection system, both of which are projected to finish in 2017. The 2018 projection includes replacement of the reactor vessel head based on industry recommendation and to address end-of-life.

At Robinson, engineering, operations, and maintenance teams have continued the momentum of making significant improvements in system and component performance. The Company's development of high intensity teams for major modification work included in the fall 2013 outage proved successful along with enhanced training and qualification program efforts. Other efforts underway include implementing upgrades to primary coolant system and steam generator make-up capability, as well as electrical modifications for backup power to support Fukushima requirements. Completion of a new on-site building for storage of reusable contaminated equipment for outages is on schedule for the end of 2014. This effort will greatly improve load-in and load-out of containment in future outages. With the projected 2015 installation of new Westinghouse shutdown reactor coolant pump seals on all three pumps, DEP is also reducing risk of core damage from a loss of seal cooling.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

DUKE ENERGY PROGRESS
SOUTH CAROLINA ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS
NUCLEAR CAPACITY FACTOR PURSUANT TO S.C. CODE ANN. § 58-27-865(F)
REVIEW PERIOD OF MARCH 2013 THROUGH FEBRUARY 2014

1	Nuclear System Actual Net Generation During Review Period	26,901,281	MWH
2	Total Number of Hours During 2013 portion of Review Period	8,760	
3	Nuclear System MDC During 2013 portion of Review Period	3,539	MW
4	Reasonable Nuclear System Reductions	4,683,239	MWH
5	Nuclear System Capacity Factor ((L1/(L2a*L3a)-L4)*100	102.21	%

DUKE ENERGY PROGRESS
SOUTH CAROLINA ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS
NUCLEAR OUTAGE DATA FOR REVIEW PERIOD OF
MARCH 2013 THROUGH FEBRUARY 2014

Nuclear Outages Lasting One Week Or More - Review Period

Station/Unit	Date of Outage	Explanation of Outage
Brunswick 1	5/18/2013-5/29/2013	Scheduled maintenance to address recirculation pump 1B seal degradation and replace 2 safety related transformers.
Brunswick 2	3/2/2013-5/9/2013	Scheduled Refueling - EOC 21; includes 13 day extension.
Harris 1	5/15/2013-6/7/2013	Unscheduled maintenance to repair head penetration.
Harris 1	11/9/2013-12/11/2013	Scheduled Refueling - EOC 18; includes 6 day extension.
Robinson 2	9/14/2013-11/4/2013	Scheduled Refueling - EOC 28.

BEFORE

THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2014-1-E

In Re:	)
	)
Duke Energy Progress, Inc. Annual Review of Base Rates for Fuel Costs	)
	)
	)

T. PRESTON GILLESPIE, JR.
CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

MAY 8, 2014

DUKE ENERGY PROGRESS
SOUTH CAROLINA ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS
NUCLEAR OUTAGE SCHEDULE FOR BILLING PERIOD OF
JULY 2014 THROUGH JUNE 2015

Scheduled Nuclear Outages Lasting One Week Or More - Billing Period

Station/Unit	Date of Outage[1]	Explanation of Outage

REDACTED

[1] This exhibit represents DEP's current plan, which is subject to change based on fluctuations in operational and maintenance requirements.

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2014-1-E

In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Progress, Inc.	))))	**DIRECT TESTIMONY OF KIMBERLY D. MCGEE FOR DUKE ENERGY PROGRESS, INC.**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kimberly D. McGee, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates Manager supporting both Duke Energy Progress, Inc. ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC")(collectively, the "Companies").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1989 with Deloitte and Touche, LLP as a staff auditor. In 1992, I began working with DEC (formerly known as Duke Power Company) as a staff accountant and have held a variety of positions in the finance organization. From 1997 until 2009, I worked for Wachovia Bank (now known as Wells Fargo) in a variety of finance and regulatory positions. I rejoined DEC in January 2009 as a Lead Accountant in Financial Reporting. I joined the Rates Department in 2011 as Manager, Rates and Regulatory Filings.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. No. I have not previously testified before the Public Service Commission of South Carolina ("PSCSC" or the "Commission"). I have previously testified, however, before the North Carolina Utilities Commission supporting the rate calculation for DEC's Demand Side Management and Energy Efficiency Rider in Docket No. E-7, Sub 1031.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide DEP's actual fuel and environmental cost data for March 1, 2013 through February 28, 2014 (the "review period"), the projected fuel and environmental cost information for March 1, 2014 through June 30, 2014 (the "forecast period"), and DEP's proposed fuel factors by customer class for July 1, 2014 through June 30, 2015 (the "billing period"). I will provide six exhibits to support my testimony.

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE REVIEW PERIOD?

A. Actual test period kilowatt hour ("kWh") generation, kWh sales, fuel-related revenues, and fuel-related expenses were taken from DEP's books and records. These books, records, and reports of DEP are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate DEP's electric rates.

In addition, independent auditors perform an annual audit to provide assurance that, in all material respects, internal accounting controls are operating effectively and DEP's financial statements are accurate.

Q. DOES DEP PURCHASE POWER AND HOW ARE THESE COSTS RECORDED?

A. Yes. The Company continuously evaluates purchasing power if it can be reliably procured and delivered at a price that is less than the variable cost of DEP's generation. In accordance with § 58-27-865(A) of the Code of Laws of South

Carolina ("S.C. Code Ann." or the "Code"), DEP recovers from its South Carolina retail customers an amount that is the lower of the purchase price or DEP's avoided variable cost for generating an equivalent amount of power for its economy purchases.

The Company also purchases power from certain suppliers that are treated as firm generation capacity purchases. In accordance with the statute, all amounts paid to these suppliers are recorded as recoverable fuel costs with the exception of capacity charges. DEP also purchases (and sells) power to DEC as a result of the Joint Dispatch Agreement ("JDA") described in Company witness Weintraub's testimony. According to his testimony, under the joint dispatch process, the energy cost attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies.

Q. PLEASE EXPLAIN MCGEE EXHIBIT NO. 1.

A. McGee Exhibit No. 1 is a summary of DEP's recommended base fuel rate of 2.981¢/kWh for the billing period, consisting of a projected component of 2.654 ¢/kWh for the recovery of the South Carolina retail share of the $1.5 billion of projected system fuel expense, and a true-up component of 0.304¢/kWh to collect the projected $19.6 million under-recovery from South Carolina customers. DEP's recommended Environmental rate of .042¢/kWh consists of a projected component of 0.058¢/kWh for the recovery of $1.4 million of projected South Carolina environmental expenses, and a true-up component of (0.016)¢/kWh to return to South Carolina customers $0.4 million of over-recovery. The environmental factor for General Service demand customers is 14¢/kW to recover $1.3 million of projected South Carolina environmental expenses offset by a true-up component of $69,385 of over-collections.

Q. HOW DID DEP'S FUEL REVENUE BILLINGS COMPARE TO THE FUEL COSTS INCURRED DURING THE MARCH 2013 TO JUNE 2014 TIME PERIOD?

A. McGee Exhibit No. 2 is a monthly comparison of fuel revenues billed to South Carolina retail customers to the actual and estimated jurisdictional fuel costs attributable to those sales. As shown on Exhibit 2, the projected DEP fuel recovery status at June 30, 2014 is an under-recovery of $19.6 million. This balance is primarily the result of extreme weather conditions in January of 2014 which resulted in higher fuel costs.

Q. PLEASE EXPLAIN MCGEE EXHIBIT NO. 3.

A. McGee Exhibit No. 3 presents DEP's recommended projected base fuel rate of 2.654¢/kWh for the billing period for the recovery of South Carolina retail share of $1.5 billion of projected system fuel expense.

The fuel forecast supporting the projected fuel cost was generated by an hourly dispatch model that considers the latest forecasted fuel prices, outages at the generating plants based on planned maintenance and refueling schedules, forced outages based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchase and off-system sales opportunities. In addition, the forecasting model reflects the joint dispatch of the combined power supply resources of DEP and DEC as described by Company witness Weintraub.

Q. PLEASE PROVIDE A STATUS UPDATE OF ENVIRONMENTAL COST COLLECTION AND EXPLAIN HOW THESE COSTS HAVE BEEN TREATED IN THIS FILING.

A. During the review period, DEP recovered variable environmental costs and the costs of emission allowances through the environmental component of the fuel rate. Environmental costs allocated to the South Carolina retail jurisdiction during the review period were approximately $2.0 million as shown on McGee Exhibit No. 4. The Company currently estimates that its deferred environmental cost balance will be an over-collection of $0.4 million at June 30, 2014.

Q. HAVE YOU PROVIDED A FORECAST OF ENVIRONMENTAL COSTS?

A. Yes, McGee Exhibit No. 5 presents DEP's estimated system environmental costs for the billing period of $23.0 million. The South Carolina retail portion is forecasted to be approximately $2.7 million.

Q. PLEASE DESCRIBE EMISSION-REDUCING CHEMICALS THAT DEP WILL INCLUDE IN THE PROPOSED FUEL RATE IN THIS FILING.

A. As Company witness Miller explains more specifically in his testimony, DEP uses emission-reducing chemicals at its fossil/hydro plants to help it provide low cost, reliable electric generation for its customers while also complying with state and federal environmental control obligations. As a result, DEP has included the cost of magnesium hydroxide, calcium carbonate, ammonia, urea, limestone, lime, and hydrated lime incurred during the review period in its fuel cost recovery application.

Q. HOW DID DEP ALLOCATE ENVIRONMENTAL COSTS?

A. Environmental costs were allocated to Residential, General Service (non-demand), and General Service (demand) rate classes based upon the coincident peak experienced during the review period. This allocation is shown on McGee Exhibit No. 4. Rates were designed based on costs allocated to the respective rate classes and the projected energy consumption for the Residential and General Service (non-demand) schedules. The rate for the General Service (demand) class was based on projected annual demand. All allocations were consistent with the methodology approved by this Commission in DEP's 2007 fuel review proceeding, Order No. 2007-440 issued July 20, 2007. This methodology has been consistently used in each fuel case since the issuance of this Order.

Q. HAVE YOU PRESENTED DEP'S PROPOSED FUEL FACTORS?

A. Yes. McGee Exhibit No. 1 presents proposed fuel rates including an amount added to account for the 5% discount provided to residential customers under DEP's SC Residential Service Energy Conservation Discount Rider RECD-2C.

Q. WHY DOES DEP PROPOSE INCLUSION OF THE EFFECTS OF RIDER RECD-2C?

A. The Company should not reflect fuel revenue collections for 100% of its fuel billings while simultaneously providing a 5% discount on the total bill as required by Rider RECD-2C. As shown on McGee Exhibit No.6, this discount impacts approximately 15% of DEP's South Carolina residential sales. The Company's request in this proceeding is consistent with this Commission's Orders issued in all of DEP's fuel proceedings since 2009.

Q. DO YOU BELIEVE DEP'S ACTUAL FUEL COSTS INCURRED DURING THE PERIOD WERE REASONABLE?

A. Yes. I believe the costs were reasonable and that DEP has demonstrated that it met the criteria set forth in § 58-27-865(F) of the Code. These costs also reflect DEP's continuing efforts to maintain reliable service and an economical generation mix, thereby minimizing the total cost of providing service to DEP's South Carolina retail customers.

Q. HOW ARE MERGER FUEL-RELATED SAVINGS HANDLED IN DEP'S RECOMMENDED FUEL RATES?

A. As Company witness Weintraub states in his testimony, merger fuel-related savings automatically flow through to DEP's retail customers through the fuel and fuel-related cost component of customers' rates. Actual merger savings during the review period are included in the true-up portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which are the result of using the combined systems' lowest cost available generation to meet total customer demand, are also reflected in the cost of fossil fuel, as well as the projected cost purchases and sales that include the purchases and sales between

DEP and DEC. Actual and projected savings related to the procurement of nuclear fuel are reflected in the cost of nuclear fuel.

Q. WHAT IS THE IMPACT TO CUSTOMERS' BILLS IF THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS ARE APPROVED BY THE COMMISSION?

A. The impact of the proposed fuel rate increase for an average residential customer using 1000 kWh per month is an increase of \$0.35, or 0.3%. Impacts for commercial and industrial customers vary by customer, but are approximately 0.6% and 0.8%, respectively.

	Residential	General Service Non-Demand	General Service Demand [1]	Lighting
Proposed Total Fuel Factor in ¢/kWh	3.023	2.997	2.958	2.958
Existing Total Fuel Factor in ¢/kWh	2.988	2.957	2.910	2.910

[1] The environmental rate for these customers is 14 ¢/kW

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL FACTOR?

A. A number of factors contribute to the increase in the proposed total fuel cost factors for all customer classes. Total fuel costs projected for the billing period, including environmental, are declining primarily due to lower coal prices, as well as the expected suspension of the U.S. Department of Energy ("DOE") nuclear waste disposal fees beginning in May 2014, as discussed in Company witness Church's testimony. This decline is offset by a \$19.6 million under-collection of fuel costs. This large under-collection was primarily due to the extreme weather conditions experienced in January 2014 during the Polar Vortex which led to higher fuel costs. The resulting increased usage required more frequent operation of DEP's higher cost generating units as well as an increase in purchases of power at higher costs. The high demand across the country for electricity led to increases in prices which had a significant impact on DEP since the majority of its generation consists of gas-fired generation. The fuel rate increase experienced during this time would have been higher had it not been for the ability of the Company to leverage its diverse generating resources and utilize the benefits of joint dispatch from the combined portfolio of DEP's and DEC's resources.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
CALCULATION OF TOTAL FUEL COMPONENT
BILLING PERIOD JULY 31, 2014 TO JUNE 30, 2015

Line No.	Description	Reference	Customer Class Cents / kWh Residential	General Service (non demand)	Lighting	General Service (demand)
	Base Fuel Costs					
1	Base Fuel Cost Component Under/ (Over) Collection at June 2014	Exhibit 2	0.304	0.304	0.304	0.304
2	Base Fuel Cost Component Projected Billing Period	Exhibit 3	2.654	2.654	2.654	2.654
3	Total Base Fuel Cost Component	Line 1 + Line 2	2.958 [1]	2.958	2.958	2.958
4	Total Base Fuel Cost Component Increased for RECD	Line 3 * RECD factor	2.981			
	Environmental Costs		Cents / kWh			Cents / kW
5	Environmental Component Under / (Over) Collection at June 2014	Exhibit 4 Page 1-3	(0.016)	(0.013)	N/A	(1)
6	Environmental Component Projected Billing Period	Exhibit 5	0.058	0.052	N/A	15
7	Total Environmental Component	Line 5 + 6	0.042 [1]	0.039	N/A	14 [2]
8	Total Environmental Cost Component Increased for RECD	Line 7 * RECD factor	0.042			
9	Total Fuel Cost Factor	Sum Total Base Fuel + Total Environmental	**3.023**	**2.997**	**2.958**	**2.958**

Notes:

[1] RECD factor is .7683% and is calculated on Exhibit 6

[2] The environmental rate for these customers is 14 cents per kW as calculated on exhibits 4 & 5

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
CALCULATION OF BASE FUEL OVER / (UNDER) RECOVERY
ACTUAL AND ESTIMATED COSTS AND REVENUES MARCH 2013 - JUNE 2014

Line No.	Description	Reference	Review Period March 2013	Review Period April 2013	Review Period May 2013	Review Period June 2013	Review Period July 2013	Review Period August 2013
1	Coal		$ 59,023,496	$ 43,097,099	$ 39,394,507	$ 68,394,024	$ 74,721,746	$ 71,474,074
2	Gas		44,913,344	47,453,872	55,019,111	56,372,613	62,313,254	61,295,186
3	Nuclear Fuel		12,195,462	11542621	10,962,560	14,761,640	16,348,895	15,487,581
4	Purchased Power		40,417,205	16,895,548	27,855,841	21,117,955	27,227,787	29,984,211
5	Fuel Expense Recovered Through Intersystem Sales		(11,622,842)	(15,683,151)	(11,760,254)	(23,159,033)	(24,063,728)	(27,632,522)
6	Total Fuel Costs	Sum Lines 1 through 5	144,926,665	103,305,989	121,471,765	137,487,199	156,547,954	150,608,530
7	Total System KWH Sales		4,396,486,986	4,256,166,018	3,849,422,774	4,292,511,033	5,050,038,599	5,246,619,945
8	Fuel Costs Incurred ¢/kwh	Line 6 / Line 7 * 100	3.296	2.427	3.156	3.203	3.100	2.871
9	Fuel Costs Billed ¢/kwh	calc Rev Billed $ / Line 10 * 100	2.629	2.628	2.628	2.636	2.910	2.910
10	SC Retail Sales KWH		474,712,940	554,895,417	452,740,595	466,779,249	602,531,741	613,182,769
11	Over / (Under) Current Month	(Line 9 - Line 8) * Line 10 / 100	(3,168,328)	1,114,187	(2,388,586)	(2,646,429)	(1,144,423)	241,704
12	Over / (Under) Cumulative Balance - February 2013	Prior Annual Filing	895,513					
13	Accounting Adjustment(s)							
14	Over / (Under) Cumulative Balance	Prior Mo Cum Bal + Line 11 + Line 13	(2,272,815)	(1,158,628)	(3,547,214)	(6,193,643)	(7,338,066)	(7,096,362)

Line No.	Class	Reference	Review Period September 2013	Review Period October 2013	Review Period November 2013	Review Period December 2013	Review Period January 2014	Review Period February 2014	Review Period Twelve Months Ended Feb-14
15	Coal		50,932,314	36,588,724	48,338,863	39,417,040	64,711,988	72,722,487	668,816,362
16	Gas		56,429,193	57,822,803	65,746,673	70,265,959	160,856,870	44,190,661	782,679,539
17	Nuclear Fuel		13,579,070	12,578,269	11,895,873	15,333,995	16,231,806	14,943,059	165,860,831
18	Purchased Power		20,695,746	18,165,677	25,578,317	22,340,333	87,646,010	33,019,235	370,943,865
19	Fuel Expense Recovered Through Intersystem Sales		(14,344,063)	(14,164,285)	(15,633,999)	(22,265,629)	(46,021,193)	(22,880,038)	(249,230,737)
20	Total Fuel Costs	Sum Lines 15 through 19	127,292,260	110,991,188	135,925,727	125,091,698	283,425,481	141,995,404	1,739,069,860
21	Total System KWH Sales		4,425,821,775	4,051,620,579	3,941,130,262	4,605,941,090	5,389,113,675	4,912,803,218	54,417,675,954
22	Fuel Costs Incurred ¢/kwh	Line 20 / Line 21 * 100	2.876	2.739	3.449	2.716	5.259	2.890	3.196
23	Fuel Costs Billed ¢/kwh	calc Rev Billed $ / Line 10 * 100	2.910	2.910	2.910	2.911	2.911	2.911	2.824
24	SC Retail Sales KWH		518,884,686	500,618,334	468,689,255	498,489,160	612,208,970	570,388,942	6,334,122,058
25	Over / (Under) Recovered Current Month	(Line 23 - Line 22) * Line 24 / 100	175,761	853,920	(2,525,777)	972,667	(14,376,029)	117,995	(22,773,338)
26	Accounting Adjustment(s)		199,743	13,274				97,372	310,389
27	Over / (Under) Recovered Cumulative Balance	Prior Mo Cum Bal + Line 25 + Line 26	(6,720,858)	(5,853,664)	(8,379,440)	(7,406,774)	(21,782,803)	(21,567,436)	(21,567,436)

Line No.	Description	Reference	Estimated March 2014	Estimated April 2014	Estimated May 2014	Estimated June 2014
28	Coal		65,498,436	18,148,826	29,364,590	50,327,753
29	Gas		70,681,262	64,052,010	56,659,755	72,083,058
30	Nuclear Fuel		11,629,348	12,483,177	13,824,784	13,688,568
31	Purchased Power		40,484,955	16,488,297	20,358,001	25,646,613
32	Fuel Expense Recovered Through Intersystem Sales		(17,939,815)	(15,265,558)	(17,043,037)	(33,088,879)
33	Total Fuel Costs	Sum Lines 28 - 32	170,354,186	95,906,751	103,164,093	128,657,113
34	Total System KWH Sales		4,396,971,975	3,684,122,704	4,236,064,441	4,858,782,381
35	Fuel Costs Incurred ¢/kwh	Line 33 / Line 34 * 100	3.874	2.603	2.435	2.648
36	Fuel Costs Billed ¢/kwh		2.911	2.911	2.911	2.911
37	SC Retail Sales KWH		512,144,615	450,967,276	509,440,381	559,031,474
38	Over / (Under) Recovered Current Month	(Line 36 - Line 35) * Line 37 / 100	(4,935,764)	1,386,106	2,421,025	1,468,459
39	Accounting Adjustment(s)		1,673,255			
40	Over / (Under) Recovered Cumulative Balance	Prior Mo Cum Bal + Line 38 + Line 39	(24,829,945)	(23,443,839)	(21,022,814)	(19,554,355)

41	SC Projected SC Retail Sales July 2014 - June 2015		6,440,968,739	
42	SC Base Fuel Increment / (Decrement) Calculated Rate (cents / kWh)	Line 40 / Line 41 * 100	0.304	¢/kWh

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
PROJECTED BILLING PERIOD BASE FUEL COSTS
FOR THE 12 MONTHS ENDING JULY 31, 2014 TO JUNE 30, 2015

Line No.	Description	Reference	July 2014	August 2014	September 2014	October 2014	November 2014	December 2014
1	Coal		$ 63,804,808	$ 50,232,382	$ 42,746,498	$ 23,215,817	$ 26,932,561	$ 56,154,626
2	Gas		78,215,713	$ 77,494,462	$ 62,514,776	$ 51,316,987	$ 50,412,503	$ 41,792,997
3	Nuclear Fuel		14,507,240	14,507,240	13,356,909	14,156,344	14,543,986	13,984,620
4	Purchased Power		29,435,720	27,735,322	21,673,592	19,759,037	16,321,210	22,305,840
5	Fuel Expense Recovered Through Intersystem Sales		(36,871,717)	(34,087,361)	(17,389,093)	(15,183,619)	(17,166,624)	(7,464,678)
6	Total Fuel Costs	Sum Lines 1 through 5	$ 149,091,763	135,882,044	122,902,680	93,264,566	91,043,636	126,773,405
7	Projected Total System Sales from July 14 - June 15 kWh		5,505,904,133	5,163,088,819	4,657,955,526	3,916,946,610	3,937,838,616	4,937,271,337
8	System Cost per kWh (¢/kwh)	Line 6 / Line 7 * 100	2.708	2.632	2.639	2.381	2.312	2.568
9	Projected SC Retail Sales July 14 - June 15 kWh		646,242,413	581,120,628	559,168,065	479,874,821	470,781,977	545,893,455
10	SC Base Fuel Costs	Line 8 * Line 9 / 100	$ 17,499,291	$ 15,293,918	$ 14,753,952	$ 11,426,073	$ 10,884,576	$ 14,016,806

Line No.	Description	Reference	January 2015	February 2015	March 2015	April 2015	May 2015	June 2015	12 Month Total
11	Coal		$ 71,291,200	$ 60,710,507	$ 20,605,208	$ 33,492,745	$ 37,325,550	$ 46,461,136	532,973,040
12	Gas		40,269,831	39,443,029	72,137,007	57,420,931	65,722,573	67,775,655	704,516,463
13	Nuclear Fuel		14,316,360	12,715,095	11,369,547	9,648,659	10,046,068	14,116,763	157,268,831
14	Purchased Power		25,115,861	17,487,521	21,854,655	20,162,829	23,386,989	25,387,617	270,626,192
15	Fuel Expense Recovered Through Intersystem Sales		(10,856,751)	(12,279,392)	(10,199,859)	(11,902,492)	(13,929,560)	(20,425,927)	(207,757,074)
16	Total Fuel Costs	Sum Lines 11 through 15	140,136,502	118,076,760	115,766,558	108,822,672	122,551,621	133,315,244	1,457,627,451
17	Projected Total System Sales from July 14 - June 15 kWh		5,166,274,277	4,405,507,870	4,213,562,874	3,854,463,212	4,240,192,249	4,925,714,406	54,924,719,930
18	System Cost per kWh (¢/kwh)	Line 16 / Line 17 * 100	2.713	2.680	2.747	2.823	2.890	2.707	2.654
19	Projected SC Retail Sales July 14 - June 15		609,059,628	499,292,692	484,622,017	477,209,709	508,652,370	579,050,964	6,440,968,739
20	SC Base Fuel Costs	Line 18 * Line 19 / 100	$ 16,520,897	$ 13,382,081	$ 13,314,865	$ 13,473,014	$ 14,701,261	$ 15,672,107	170,943,310

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
CALCULATION OF ENVIRONMENTAL OVER / (UNDER) RECOVERY
ACTUAL AND ESTIMATED COSTS AND REVENUES MARCH 2013 - JUNE 2014

Line No.			Residential
1	Summer 2013 Firm Coincident Peak (CP) kWs		
2		CP %	45.86%

Line No.	Description	Reference	Review Period March 2013	Review Period April 2013	Review Period May 2013	Review Period June 2013	Review Period July 2013	Review Period August 2013
3	Total Reagents		$ 1,200,407	$ 1,130,674	$ 1,079,229	$ 1,817,344	$ 1,916,731	$ 1,983,076
4	Emission Allowances		33,524	53,003	58,234	92,491	110,320	105,829
5	Off-System Sales		(4,620)	(195,828)	(73,424)	(330,019)	(277,483)	(402,273)
6	Net Environmental Costs	Sum Lines 3 thru 5	$ 1,229,311	$ 987,849	$ 1,064,039	$ 1,579,816	$ 1,749,568	$ 1,686,632
7	Total System Sales kWh		4,396,486,985	4,256,166,018	3,849,422,774	4,292,511,033	5,050,038,599	5,246,619,945
8	Environmental System Costs Incurred ¢/kwh	Line 6 / Line 7*100	0.0280	0.0232	0.0276	0.0368	0.0346	0.0321
9	SC Retail Sales kWh		474,712,940	554,895,417	452,740,595	466,779,249	602,531,741	613,182,769
10	SC Environmental Costs	Line 8 * Line 9 / 100	$ 132,735	$ 128,790	$ 125,144	$ 171,793	$ 208,745	$ 197,120
11	Residential Environmental Cost Allocated by Firm CP	Line 10 * Line 2	$ 60,877	$ 59,067	$ 57,395	$ 78,790	$ 95,737	$ 90,405
12	SC Residential kWh Sales		202,938,346	172,537,631	123,298,278	156,897,557	182,885,291	208,064,269
13	SC Residential Environmental Costs Incurred ¢/kwh	Line 11 / Line 12 * 100	0.030	0.034	0.047	0.050	0.052	0.043
14	SC Residential Environmental Costs Billed ¢/kwh		0.050	0.050	0.050	0.050	0.054	0.054
15	SC Residential Environmental Costs Over / (Under) Recovery	(Line 14 - Line 13) * Line 12 / 100	$ 40,592	$ 27,202	$ 4,254	$ (341)	$ 3,021	$ 21,949
16	Over / (Under) Cumulative Balance - February 2013	Prior Year Annual Filing	$ 158,665					
17	Cumulative SC Residential Environmental Costs Over / (Under) Recovery	Line 15 + Prior Month Cum. Bal	$ 199,257	$ 226,459	$ 230,713	$ 230,372	$ 233,393	$ 255,342

Line No.	Description	Reference	Review Period September 2013	Review Period October 2013	Review Period November 2013	Review Period December 2013	Review Period January 2014	Review Period February 2014	Review Period Twelve Months Ended Feb 2014
18	Total Reagents		$ 1,471,862	$ 1,327,027	$ 1,892,458	$ 863,979	$ 2,280,309	$ 2,056,195	$ 19,019,331
19	Emission Allowances		84,764	40,860	48,801	33,739	33,618	47,272	$ 742,455
20	Off-System Sales		(72,153)	(206,317)	(188,589)	(301,157)	(105,062)	(126,872)	$ (2,283,797)
21	Net Environmental Costs	Sum Lines 18 thru 20	$ 1,484,473	$ 1,161,570	$ 1,752,710	$ 596,561	$ 2,208,865	$ 1,976,595	$ 17,477,989
22	Total System Sales		4,425,821,775	4,051,620,579	3,941,130,262	4,605,941,090	5,389,113,675	4,912,803,218	$ 54,417,675,954
23	Environmental System Costs Incurred ¢/kwh	Line 21 / Line 22 * 100	0.0335	0.0287	0.0445	0.0130	0.0410	0.0402	
24	SC Retail Sales kWh		518,884,686	500,618,334	468,689,255	498,489,160	612,208,970	570,358,942	$ 6,334,122,058
25	SC Environmental Costs	Line 23 * Line 24 / 100	$ 174,040	$ 143,524	$ 208,437	$ 64,564	$ 250,929	$ 229,488	$ 2,035,310
26	Residential Environmental Cost Allocated by Firm CP	Line 25 * Line 2	$ 79,820	$ 65,824	$ 95,596	$ 29,611	$ 115,084	$ 105,250	$ 933,457
27	SC Residential kWh Sales		163,002,066	138,278,963	140,750,224	201,623,601	254,869,274	242,361,902	2,187,507,402
28	SC Residential Environmental Costs Incurred ¢/kwh	Line 26 / Line 27 * 100	0.049	0.048	0.068	0.015	0.045	0.043	0.043
29	SC Residential Environmental Costs Billed ¢/kwh		0.054	0.054	0.054	0.054	0.054	0.054	0.052
30	SC Residential Environmental Costs Over / (Under) Recovery	(Line 29 - Line 28) * Line 27 / 100	$ 8,201	$ 8,846	$ (19,591)	$ 79,266	$ 22,545	$ 25,625	$ 221,570
31	Cumulative SC Residential Environmental Costs Over / (Under) Recovery	Line 30 + Prior Month Cum. Bal	$ 263,543	$ 272,389	$ 252,799	$ 332,064	$ 354,610	$ 380,235	$ 380,235

Line No.	Description	Reference	Estimated March 2014	Estimated April 2014	Estimated May 2014	Estimated June 2014
32	Total Reagents		$ 2,529,136	$ 973,971	$ 1,384,353	$ 2,162,961
33	Emission Allowances		50,088	17,550	36,395	66,223
34	Off-System Sales		(68,558)	(5,576)	(12,601)	(9,638)
35	Net Environmental Costs	Sum Lines 32 thru 34	$ 2,510,666	$ 985,945	$ 1,408,150	$ 2,219,546
36	Total System Sales		4,396,971,975	3,684,122,704	4,236,064,441	4,858,782,381
37	Environmental System Costs Incurred ¢/kwh	Line 35 / Line 36 * 100	0.0571	0.0268	0.0332	0.0457
38	SC Retail Sales kWh		512,144,615	450,967,276	509,440,381	559,031,474
39	SC Environmental Costs	Line 37 * Line 38 /100	$ 292,434	$ 120,688	$ 169,348	$ 255,372
40	Residential Environmental Cost Allocated by Firm CP	Line 39 * Line 2	$ 134,119	$ 55,351	$ 77,668	$ 117,122
41	SC Residential kWh Sales		187,463,978	117,524,249	128,645,092	198,599,092
42	SC Residential Environmental Costs Incurred ¢/kwh	Line 40 / Line 41 * 100	0.072	0.047	0.060	0.059
43	SC Residential Environmental Costs Billed ¢/kwh		0.054	0.054	0.054	0.054
44	SC Residential Environmental Costs Over / (Under) Recovery	(Line 43 - Line 42) * Line 41 / 100	$ (32,889)	$ 8,112	$ (8,200)	$ (9,878)
45	Cumulative SC Residential Environmental Costs Over / (Under) Recovery	Line 44 + Prior Month Cum. Bal	$ 347,346	$ 355,458	$ 347,258	$ 337,380
46	SC Projected Residential Sales July 2014 - June 2015					2,137,377,003
47	SC Residential Environmental Increment / (Decrement) Calculated Rate (¢/kwh)	-Line 45 / Line 46 * 100				(0.016)

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
CALCULATION OF ENVIRONMENTAL OVER / (UNDER) RECOVERY
ACTUAL AND ESTIMATED COSTS AND REVENUES MARCH 2013 - JUNE 2014

General Service (non demand)

Line No.	Description		
1	Summer 2013 Firm Coincident Peak (CP) kW's		
2		CP %	5.84%

Line No.	Description	Reference	Review Period March 2013	Review Period April 2013	Review Period May 2013	Review Period June 2013	Review Period July 2013	Review Period August 2013
3	Total Reagents		$ 1,200,407	$ 1,130,674	$ 1,079,229	$ 1,817,344	$ 1,916,731	$ 1,983,076
4	Emission Allowances		33,524	53,003	58,234	92,491	110,320	105,829
5	Off-System Sales		(4,620)	(195,828)	(73,424)	(330,019)	(277,483)	(402,273)
6	Net Environmental Costs	Sum Lines 3 thru 5	$ 1,229,311	$ 987,849	$ 1,064,039	$ 1,579,816	$ 1,749,568	$ 1,686,632
7	Total System Sales kWh		4,396,488,986	4,256,166,018	3,849,427,774	4,292,511,033	5,050,038,599	5,246,619,945
8	Environmental System Costs Incurred ¢/kwh	Line 6 / Line 7 * 100	0.028	0.023	0.028	0.037	0.035	0.032
9	SC Retail Sales kWh		474,712,940	554,895,417	452,740,595	466,779,249	602,531,741	613,182,769
10	SC Environmental Costs	Line 8 * Line 9 / 100	$ 132,735	$ 128,790	$ 125,144	$ 171,793	$ 208,745	$ 197,120
11	General Service (non-demand) Environmental Cost Allocated by Firm CP	Line 10 * Line 2	$ 7,746	$ 7,516	$ 7,303	$ 10,026	$ 12,182	$ 11,504
12	SC General Service (non-demand) kWh Sales		23,968,140	22,673,744	19,978,092	24,527,376	26,946,883	31,206,540
13	SC General Service (non-demand) Environmental Costs Incurred ¢/kwh	Line 11 / Line 12 * 100	0.032	0.033	0.037	0.041	0.045	0.037
14	SC General Service (non-demand) Environmental Costs Billed ¢/kwh		0.050	0.050	0.050	0.050	0.047	0.047
15	SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	(Line 14 - Line 13) * Line 12 / 100	$ 4,238	$ 3,821	$ 2,686	$ 2,238	$ 483	$ 3,163
16	Over / (Under) Cumulative Balance - February 2013	Prior Year Annual Filing	$ 19,849					
17	Cumulative SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	Line 15 + Prior Month Cum Bal	$ 24,087	$ 27,908	$ 30,593	$ 32,831	$ 33,314	$ 36,478

Line No.	Description	Reference	Review Period September 2013	Review Period October 2013	Review Period November 2013	Review Period December 2013	Review Period January 2014	Review Period February 2014	Review Period Twelve Months Ended Feb 2014
18	Total Reagents		$ 1,471,862	$ 1,327,027	$ 1,892,498	$ 863,979	$ 2,280,309	$ 2,056,195	$ 19,019,331
19	Emission Allowances		84,764	40,860	48,801	33,739	33,618	47,272	$ 742,455
20	Off-System Sales		(72,153)	(206,317)	(188,589)	(301,157)	(105,062)	(126,872)	$ (2,283,797)
21	Net Environmental Costs	Sum Lines 18 thru 20	$ 1,484,473	$ 1,161,570	$ 1,752,710	$ 596,561	$ 2,208,865	$ 1,976,595	$ 17,477,989
22	Total System Sales		4,425,821,775	4,051,620,579	3,941,130,262	4,605,941,090	5,389,113,675	4,912,803,218	$ 54,417,675,954
23	Environmental System Costs Incurred ¢/kwh	Line 21 / Line 22 * 100	0.034	0.029	0.044	0.013	0.041	0.040	
24	SC Retail Sales kWh		518,884,686	500,618,334	468,689,255	498,489,160	612,208,970	570,388,942	$ 6,334,122,058
25	SC Environmental Costs	Line 23 * Line 24 / 100	$ 174,040	$ 143,524	$ 208,437	$ 64,564	$ 250,929	$ 229,488	$ 2,035,310
26	General Service (non demand) Environmental Cost Allocated by Firm CP	Line 25 * Line 2	$ 10,157	$ 8,376	$ 12,164	$ 3,768	$ 14,644	$ 13,393	$ 118,778
27	SC General Service (non-demand) kWh Sales		26,535,195	23,573,217	20,816,428	25,065,348	28,981,403	26,445,511	300,718,877
28	SC General Service (non-demand) Environmental Costs Incurred ¢/kwh	Line 26 / Line 27 * 100	0.038	0.036	0.058	0.015	0.051	0.051	0.039
29	SC General Service (non-demand) Environmental Costs Billed ¢/kwh		0.047	0.047	0.047	0.047	0.047	0.047	0.048
30	SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	(Line 29 - Line 28) * Line 27 / 100	$ 2,315	$ 2,704	$ (2,380)	$ 8,013	$ (1,023)	$ (963)	$ 25,294
31	Cumulative SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	Line 30 + Prior Month Cum Bal	$ 38,793	$ 41,496	$ 39,116	$ 47,129	$ 46,106	$ 45,143	$ 45,143

Line No.	Description	Reference	Estimated March 2014	Estimated April 2014	Estimated May 2014	Estimated June 2014
32	Total Reagents		$ 2,529,136	$ 973,971	$ 1,384,355	$ 2,162,961
33	Emission Allowances		50,088	17,550	36,395	66,223
34	Off-System Sales		(68,558)	(5,576)	(12,601)	(9,638)
35	Net Environmental Costs	Sum Lines 32 thru 34	$ 2,510,666	$ 985,945	$ 1,408,150	$ 2,219,546
36	Total System Sales		4,396,971,975	3,684,122,704	4,236,064,441	4,858,782,381
37	Environmental System Costs Incurred ¢/kwh	Line 35 / Line 36 * 100	0.057	0.027	0.033	0.046
38	SC Retail Sales kWh		512,144,615	450,967,276	509,440,381	559,031,474
39	SC Environmental Costs	Line 37 * Line 38 / 100	$ 292,434	$ 120,688	$ 169,348	$ 255,372
40	General Service (non-demand) Environmental Cost Allocated by Firm CP	Line 39 * Line 2	$ 17,066	$ 7,043	$ 9,883	$ 14,903
41	SC General Service (non-demand) kWh Sales		22,173,934	19,407,747	22,877,068	26,046,745
42	SC General Service (non-demand) Environmental Costs Incurred ¢/kwh	Line 40 / Line 41 * 100	0.077	0.036	0.043	0.057
43	SC General Service (non-demand) Environmental Costs Billed ¢/kwh		0.047	0.047	0.047	0.047
44	SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	(Line 43 - Line 42) * Line 41 / 100	$ (6,668)	$ 2,078	$ 869	$ (2,661)
45	Cumulative SC General Service (non-demand) Environmental Costs Over / (Under) Recovery	Line 44 + Prior Month Cum Bal	$ 38,475	$ 40,554	$ 41,423	$ 38,762
46	SC Projected General Service (non-demand) Sales July 2014 - June 2015					300,736,591
47	SC General Service (non-demand) Environmental Increment / (Decrement) Calculated Rate (¢/kwh)	-Line 45 / Line 46 * 100				(0.013)

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
CALCULATION OF ENVIRONMENTAL OVER / (UNDER) RECOVERY
ACTUAL AND ESTIMATED COSTS AND REVENUES MARCH 2013 - JUNE 2014

General Service (demand)

Line No	Description	Reference	
1	Summer 2013 Firm Coincident Peak (CP) kWs		
2		CP %	48.30%

Line No.	Description	Reference	Review Period March 2013	Review Period April 2013	Review Period May 2013	Review Period June 2013	Review Period July 2013	Review Period August 2013
3	Total Reagents		$ 1,200,407	$ 1,130,674	$ 1,079,229	$ 1,817,344	$ 1,916,731	$ 1,983,076
4	Emission Allowances		33,524	53,003	58,234	92,491	110,320	105,829
5	Off-System Sales		(4,620)	(195,828)	(73,424)	(330,019)	(277,483)	(402,273)
6	Net Environmental Costs	Sum Lines 3 thru 5	$ 1,229,311	$ 987,849	$ 1,064,039	$ 1,579,816	$ 1,749,568	$ 1,686,632
7	Total System Sales kWh		4,396,486,986	4,256,166,018	3,849,422,774	4,292,511,033	5,050,038,599	5,246,619,945
8	Environmental System Costs Incurred ¢/kwh	Line 6 / Line 7 * 100	0.028	0.023	0.028	0.037	0.035	0.032
9	SC Retail Sales kWh		474,712,940	554,895,417	452,740,595	466,779,249	602,531,741	613,182,769
10	SC Environmental Costs	Line 8 * Line 9 / 100	$ 132,735	$ 126,790	$ 125,144	$ 171,793	$ 208,745	$ 197,120
11	General Service (demand) Environmental Cost Allocated by Firm CP	Line 10 * Line 2	$ 64,113	$ 62,207	$ 60,446	$ 82,978	$ 100,826	$ 95,211
12	SC General Service (demand) kW Sales		664,402	686,622	645,407	657,706	710,737	786,263
13	SC General Service (demand) Environmental Costs Incurred ¢ / kW	Line 11 / Line 12 * 100	10	9	9	13	14	12
14	SC General Service (demand) Environmental Costs Billed ¢ / kW		12	12	12	12	12	12
15	SC General Service (demand) Environmental Costs Over / (Under) Recovery	(Line 14 - Line 13) * Line 12 / 100	$ 15,616	$ 20,188	$ 17,003	$ (4,053)	$ (15,537)	$ (859)
16	Over / (Under) Cumulative Balance - February 2013	Prior Year Annual Filing	$ 140,091					
17	Cumulative SC Environmental Costs Over / (Under) Recovery	Line 15 + Prior Month Cum Bal	$ 155,707	$ 175,894	$ 192,897	$ 188,844	$ 173,307	$ 172,447

Line No.	Description	Reference	Review Period September 2013	Review Period October 2013	Review Period November 2013	Review Period December 2013	Review Period January 2014	Review Period February 2014	Review Period Twelve Months Ended Feb 2014
18	Total Reagents		$ 1,471,862	$ 1,327,027	$ 1,892,498	$ 863,979	$ 2,280,309	$ 2,056,195	$ 19,019,331
19	Emission Allowances		84,764	40,860	48,801	33,739	33,618	47,272	$ 742,455
20	Off-System Sales		(72,153)	(206,317)	(188,589)	(301,157)	(105,062)	(126,872)	$ (2,283,797)
21	Net Environmental Costs	Sum Lines 18 thru 20	$ 1,484,473	$ 1,161,570	$ 1,752,710	$ 596,561	$ 2,208,865	$ 1,976,595	$ 17,477,989
22	Total System Sales kWh		4,425,821,775	4,051,620,579	3,941,130,262	4,605,941,090	5,389,113,675	4,912,803,218	$ 54,417,675,954
23	Environmental System Costs Incurred ¢/kwh	Line 21 / Line 22 * 100	0.034	0.029	0.044	0.013	0.041	0.040	0.032
24	SC Retail Sales kWh		518,884,686	500,618,334	468,689,253	498,489,160	612,208,970	570,388,942	$ 6,334,122,058
25	SC Environmental Costs	Line 23 * Line 24 / 100	$ 174,040	$ 143,524	$ 208,437	$ 64,564	$ 250,929	$ 229,488	$ 2,034,407
26	General Service (demand) Environmental Cost Allocated by Firm CP	Line 25 * Line 2	$ 84,063	$ 69,323	$ 100,677	$ 31,185	$ 121,201	$ 110,845	$ 983,075
27	SC General Service (demand) kW Sales		633,387	678,421	617,543	682,384	742,199	701,717	8,206,788
28	SC General Service (demand) Environmental Costs Incurred ¢ / kW	Line 26 / Line 27 * 100	13	10	16	5	16	16	12
29	SC General Service (demand) Environmental Costs Billed ¢ / kW		12	12	12	12	12	12	12
30	SC General Service (demand) Environmental Costs Over / (Under) Recovery	(Line 29 Line 28) * Line 27 / 100	$ (8,057)	$ 12,087	$ (26,572)	$ 50,701	$ (32,137)	$ (26,639)	$ 1,740
31	Cumulative SC General Service (demand) Environmental Costs Over / (Under) Recovery	Line 30 + Prior Month Cum Bal	$ 164,391	$ 176,478	$ 149,906	$ 200,607	$ 168,470	$ 141,831	$ 141,831

Line No.	Description	Reference	Estimated March 2014	Estimated April 2014	Estimated May 2014	Estimated June 2014
32	Total Reagents		$ 2,529,136	$ 973,971	$ 1,384,355	$ 2,162,961
33	Emission Allowances		50,088	17,550	36,395	66,223
34	Off-System Sales		(68,558)	(5,576)	(12,601)	(9,638)
35	Net Environmental Costs	Sum Lines 32 thru 34	2,510,666	985,945	1,408,150	2,219,546
36	Total System Sales kWh		4,396,971,975	3,684,122,704	4,235,064,441	4,858,782,381
37	Environmental System Costs Incurred ¢/kwh	Line 35 / Line 36 * 100	0.057	0.027	0.033	0.046
38	SC Retail Sales kWh		512,144,615	450,967,276	509,440,381	559,031,474
39	SC Environmental Costs	Line 37 * Line 38 / 100	292,434	120,688	169,348	255,372
40	General Service (demand) Environmental Cost Allocated by Firm CP	Line 39 * Line 2	$ 141,248	$ 58,293	$ 81,797	$ 123,347
41	SC General Service (demand) kW Sales		672,347	584,954	693,795	837,571
42	SC General Service (demand) Environmental Costs Incurred ¢ / kW	Line 40 / Line 41 * 100	21	10	12	15
43	SC General Service (demand) Environmental Costs Billed ¢ / kW		12	12	12	12
44	SC General Service (demand) Environmental Costs Over / (Under) Recovery	(Line 43 - Line 42) * Line 41 / 100	$ (60,567)	$ 9,501	$ 1,459	$ (22,839)
45	Cumulative SC General Service (demand) Environmental Costs Over / (Under) Recovery	Line 44 + Prior Month Cum Bal	$ 81,264	$ 90,765	$ 92,224	$ 69,385
46	SC Projected General Service (demand) kW Sales July 2014 - June 2015					8,440,978
47	SC General Service (demand) Environmental Increment / (Decrement) Calculated Rate (¢/kwh)	-Line 45 / Line 46 * 100				(1)

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
PROJECTED BILLING PERIOD ENVIRONMENTAL COSTS
FOR THE 12 MONTHS ENDING JULY 31, 2014 TO JUNE 30, 2015

Line No.	Class	Summer 2013 Firm Coincident Peak (CP) KWs	CP %
1	Residential	505,527	45.8631%
2	General Service (non demand)	64,326	5.8359%
3	General Service (demand)	532,398	48.3010%
	Total SC	1,102,251	100%

Line No.	Description	Reference	July 2014	August 2014	September 2014	October 2014	November 2014	December 2014
4	Total Reagents		$ 2,486,218	$ 2,566,959	$ 1,497,099	$ 1,387,831	$ 1,358,927	$ 2,562,459
5	Emission Allowances		77,484	80,045	45,012	29,906	30,789	65,415
6	Estimated Off-system Sales		(31,119)	(65,406)	(9,648)	(25,142)	(14,633)	(6,898)
7	Net Environmental Costs	Sum Lines 4 through 6	$ 2,532,583	$ 2,581,598	$ 1,532,463	$ 1,392,595	$ 1,375,083	$ 2,620,976
8	Projected Total System Sales from July 14 - June 15		5,505,904,133	5,163,088,819	4,657,955,526	3,916,946,610	3,937,838,616	4,937,271,337
9	Environmental System Costs Incurred ¢/kwh	Line 7 / Line 8 * 100	0.046	0.050	0.033	0.036	0.035	0.053
10	Projected SC Retail Sales July 14 - June 15		646,242,413	581,120,628	559,168,065	479,874,821	470,781,977	545,893,455
11	SC Environmental Costs	Line 9 * Line 10 / 100	297,256	290,566	183,966	170,610	164,396	289,790

Line No.	Description	Reference	January 2015	February 2015	March 2015	April 2015	May 2015	June 2015	12 Months Ended June 2015
12	Total Reagents		$ 2,946,022	$ 2,382,329	$ 1,022,143	$ 1,326,283	$ 1,503,506	$ 1,874,285	22,914,061
13	Emission Allowances		56,521	45,765	17,218	25,136	25,718	31,167	530,176
14	Estimated Off-system Sales		(114,212)	(6,815)	(9,807)	(140)	(886)	(9,872)	(294,579)
15	Net Environmental Costs	Sum Lines 12 thru 14	2,888,331	2,421,279	1,029,554	1,351,278	1,528,338	1,895,580	23,149,658
16	Projected Total System Sales from July 14 - June 15		5,166,274,277	4,405,507,870	4,213,562,874	3,854,463,212	4,240,192,249	4,925,714,406	54,924,719,930
17	Environmental System Costs Incurred ¢/kwh	line 15 / Line 16 *100	0.056	0.055	0.024	0.035	0.036	0.038	
18	Projected SC Retail Sales July 14 - June 15		609,059,628	499,292,692	484,622,017	477,209,709	508,652,370	579,050,964	6,440,968,739
19	SC Environmental Costs	Line 17 * Line 18 / 100	340,510	274,413	118,414	167,298	183,339	222,838	2,703,396
	SC Environmental Costs Allocated on CP kWs								
20	Residential	Total Line 19 * Line 1							$ 1,239,862
21	General Service (non demand)	Total Line 19 * Line 2							157,767
22	General Service (demand)	Total Line 19 * Line 3							1,305,766
23	Total SC	Sum Lines 20 through 22							$ 2,703,396
	Projected Retail Sales kWh								
24	Residential								2,137,377,003
25	General Service (non demand)								301,500,320
26	General Service (demand)								3,898,612,603
27	Lighting								103,478,814
28	Total SC	Sum Lines 24 through 27							6,440,968,739
	Projected Average Environmental Fuel Cost ¢/kWh								
29	Residential	Line 20 / Line 24 * 100							0.058
30	General Service (non demand)	Line 21 / Line 25 * 100							0.052
	Projected Average Environmental Fuel Cost ¢/kW								
31	Projected SC MW sales (General Service (demand)								8,440,978
32	General Service (demand)	Line 22 / Line 31 * 100							15 ¢/kW

McGee Exhibit 6
DOCKET NO 2014-1-E

DUKE ENERGY PROGRESS, INC.
SOUTH CAROLINA RETAIL FUEL CASE
REVENUE ADJUSTMENT FACTOR FOR RECD
FOR THE 12 MONTHS ENDING MARCH 31, 2013 TO FEBRUARY 28, 2014

Residential Adjustment Factor

(1)	Billed kWh (12ME 2/28/14)	Per Books	2,215,371,902	
(2)	Billed RECD kWh (12ME 2/28/14)		340,414,857	(a)
(3)	RECD kWh Percent of Total Billed	Line 2 / Line 1	15.3660%	
(4)	RECD Discount	RECD Discount	5.0000%	(b)
(5)	RECD Impact (Weighted Discount)	Line 3 X Line 4	0.7683%	

Notes:

(a) Energy billed and discounted pursuant to Residential Energy Conservation Discount, Rider RECD-2C

(b) Five-percent discount provided under Residential Energy Conservation Discount, Rider RECD-2C.

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2014-1-E

In the Matter of	)	**DIRECT TESTIMONY OF**
Annual Review of Base Rates	)	**JOSEPH A. MILLER, JR. FOR**
for Fuel Costs for	)	**DUKE ENERGY PROGRESS, INC.**
Duke Energy Progress, Inc.	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Miller, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am interim Vice President of Central Engineering and Services for Duke Energy Business Services, LLC, which is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Progress, Inc. ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana) in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and Investments Engineering in 2010, and was named General Manager of Strategic Engineering in July 2012 following the merger between Duke Energy and Progress Energy, Inc. I was named interim Vice President of Central Engineering and Services in February 2014.

Q. WHAT ARE YOUR DUTIES AS VICE PRESIDENT OF CENTRAL ENGINEERING AND SERVICES?

A. In this role, I am responsible for providing direction and oversight for engineering and business services including design, standards, and consulting along with strategic services, technical services such as NERC compliance, and environmental compliance for DEP's fleet of fossil and hydroelectric ("hydro" and collectively, "fossil/hydro") facilities.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before Public Service Commission of South Carolina in DEP's 2013 annual fuel proceeding in Docket No. 2013-1-E, as well as in DEC's 2012 and 2013 annual fuel proceedings in Docket Nos. 2012-3-E and 2013-3-E, respectively. I have also testified on multiple occasions on behalf of Duke Energy in proceedings before this and other state commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) describe DEP's generation portfolio and changes made since the prior year's filing, (2) discuss the performance of DEP's fossil/hydro facilities during the period of March 1, 2013 through February 28, 2014 (the "review period"), (3) provide information on significant outages that occurred during the review period, and (4) discuss DEP's environmental compliance efforts.

Q. PLEASE DESCRIBE DEP'S FOSSIL/HYDRO GENERATION PORTFOLIO.

A. The Company's fossil/hydro generation portfolio consists of 9,175[1] megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired [2] -	3,328 MWs
Combustion Turbines -	2,999 MWs
Combined Cycle Turbines -	2,626 MWs
Hydro -	222 MWs

The 3,328 MWs of coal-fired generation represent three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x burners. This inventory of coal-fired assets with emission control equipment employed enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the best cost options for coal supply.

The Company has a total of 36 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,205 MWs, or 73.5% of capacity. These 14 units are located at the Asheville, Darlington, Richmond County, and Wayne County facilities, and are equipped with water injection and/or low NO_x burners for NO_x control. The 2,626 MWs shown as "Combined Cycle Turbines" ("CC") represent

[1] As of 3/17/2014 representing DEP's ownership share.
[2] Represents DEP's 83.83% and 87.06% ownership share respectively for Mayo and Roxboro.

four power blocks. The Lee Energy Complex CC power block ("Lee CC") has a configuration of three CTs and one steam turbine. The two Richmond County power blocks located at the Smith Energy Complex consist of two CTs and one steam turbine each. The most recent CC addition began commercial operation on November 27, 2013 at Sutton Energy Complex ("Sutton CC") in Wilmington, North Carolina and consists of two CTs and one steam turbine. Within these CC power blocks, all nine CTs are equipped with low NO_x burners, SCR equipment, and carbon monoxide volatile organic compound catalysts. The steam turbines do not combust fuel and, therefore, do not require NO_x controls. The Company's hydro fleet consists of 15 units providing approximately 222 MWs of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO PORTFOLIO SINCE DEP'S 2013 ANNUAL FUEL PROCEEDING?

A. Changes within the portfolio include the addition of 622 MWs of capacity at Sutton CC. Also within the review period, DEP retired Sutton coal-fired Units 1, 2, and 3. These retirements in November 2013 reduced capacity by 553 MWs[3], retiring units that began commercial operation between 1954 and 1972. The CT fleet was reduced by a total of 261 MWs with the March 2013 retirement of the remaining units at Cape Fear and Robinson Stations that began commercial operation between 1968 and 1969.

Q. ARE OTHER CAPACITY CHANGES POSSIBLE WITHIN DEP'S FOSSIL/HYDRO PORTFOLIO IN THE NEXT FEW YEARS?

A. Yes. In February 2014, DEP announced that it has entered discussions with North Carolina Eastern Municipal Power Agency ("NCEMPA") regarding the potential

[3] Summer capacity ratings as noted in 2013 DEP Integrated Resource Plan.

purchase of NCEMPA's portions of Roxboro Unit 4 and Mayo Unit 1. This purchase, if completed, would bring DEP's ownership to 100% and add 208 MWs to DEP's coal-fired portfolio.

Q. WHAT ARE DEP'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/HYDRO FACILITIES?

A. The primary objective of DEP's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEP's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model. Like safety, environmental compliance is a "first principle" and DEP works very hard to achieve high level results.

The Company achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power options for DEP's customers. Equipment inspection and maintenance outages are generally scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE REVIEW PERIOD?

A. For the review period, DEP's total system generation was 61,538,758 MW hours ("MWHs"), of which 34,637,477 MWHs, or approximately 57%, was provided by the fossil/hydro fleet. The breakdown includes a 28% contribution from coal-fired stations, an approximately 27% contribution from gas facilities, and an approximately 2% contribution from hydro facilities.

The Company's portfolio includes a diverse mix of units that, along with additional nuclear capacity, allow DEP to meet the dynamics of customer load requirements in a logical and cost-effective manner. Additionally, DEP has utilized the Joint Dispatch Agreement ("JDA"), described further in Company witness Weintraub's testimony, which allows generating resources for DEP and DEC to be dispatched as a single system to enhance dispatching at the lowest possible cost. The cost and operational characteristics of each unit generally determine the type of customer load situation (e.g., base and peak load requirements) that a unit would be called upon or dispatched to support.

Q. HOW DID DEP COST EFFECTIVELY DISPATCH THE DIVERSE MIX OF GENERATING UNITS DURING THE REVIEW PERIOD?

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to favorable economics resulting from the low pricing of natural gas which includes the expansion of shale gas as described in Company witness Weintraub's testimony. Further, the addition of new combined cycle units within DEP's portfolio in recent years has provided

DEP with additional natural gas resources that feature state-of-the-art technology for increased efficiency, fuel flexibility, and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in both pricing and reduced emissions for customers.

Q. WHAT WAS THE HEAT RATE FOR DEP'S COAL-FIRED FLEET DURING THE REVIEW PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the average heat rate for the most active coal-fired units – excluding those retired during the review period – was 11,098 Btu/kWh. The most active station during this period was Roxboro, providing 68% of the coal production with an average of heat rate of 10,662 Btu/kWh.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEP'S FOSSIL/HYDRO FLEET DURING THE REVIEW PERIOD.

A. The Company's generating units operated efficiently and reliably during the test period. Several key measures are used to evaluate the operational performance depending on the generator type: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance (*i.e.*, forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated[4] hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability ("SR"), which represents the percentage of successful starts.

The following chart provides operation results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") representing the period 2008 through 2012.

Generator Type	Measure	Review Period Operational Results	2008-2012 NERC Average	Nbr of Units
Coal-fired Review Period	EAF	86.2%	81.6%	458
	NCF	39.8%	61.5%	
	EFOR	3.4%	8.4%	
Coal-fired Summer Peak	EAF	95.5%	n/a	n/a
Total CC Average	EAF	92.5 %	85.6%	301
	NCF	67.1%	45.2%	
	EFOR	0.7%	6.39%	
Total CT Average	EAF	90.9%	62.8%	939
	SR	98.2%	97.6%	
Hydro	EAF	94.8%	84.6%	1103

[4] Derated hours are hours the unit operation was less than full capacity.

The NERC performance metrics and number of units shown in the chart for the coal-fired units represent an average of comparable units based on capacity rating.

Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEP'S FOSSIL/HYDRO FACILITIES DURING THE REVIEW PERIOD.

A. In general, planned maintenance outages for all fossil and hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this review period to inspect and maintain plant equipment. For the review period, the most significant outages occurred in the spring of 2013. Mayo Unit 1 entered a planned maintenance outage to implement several major projects during which the more significant projects completed included a dry bottom ash conversion, the replacement of 40 coal pipe burners with new low NO_x burners, the replacement of discharge electrodes on the electrostatic precipitator ("ESP") for improved performance, and the conversion of the air heater baskets to a newer design, which is more resistant to plugging.

Also in the spring, Asheville Unit 1 entered a planned maintenance outage which involved major inspections on the turbine, generator, and balance of plant systems along with maintenance on the boiler. The more significant projects completed were rewind of the generator stator and field, replacement of the economizer section of the boiler, and air heater basket replacement. Roxboro station had planned maintenance outages on Unit 3 in the spring and Unit 4 in the fall. The Roxboro Unit 3 outage included maintenance work for the boiler, turbine, and scrubber. The more significant projects completed were replacement of condenser tubes, replacement of SCR catalyst for enhanced NO_x control, and hot reheat elbow replacements. The fall Roxboro Unit 4 outage was a planned turbine and scrubber maintenance outage. The more significant projects completed were rebundling of the condenser tubes, restoration of the turbine valves, and repairs to the ESP.

Significant outages for the CT fleet included returning Darlington Unit 12 to service in June 2013 following a complete restoration effort. The Company took the opportunity to incorporate upgrades including improved blade path thermocouples and generator controls, modified exhaust bearing tunnels, and installed new instrumentation to provide improved information and control for operators. A planned spring outage for a major turbine overhaul at Darlington Unit 13 required an extension due to the need to address rotor damage which occurred during installation transfer. The vendor completed a full examination and made needed repairs.

There were also planned outages for turbine inspections at Richmond CC and Lee CC facilities, which included maintenance activities to ensure reliability of the power blocks. Within the hydro fleet, DEP addressed end of life concerns with generator rewinds for Blewett Units 2 and 5, and Tillery Units 2 and 3.

Q. HOW DOES DEP ENSURE EMISSIONS REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. As noted above, DEP has installed pollution control equipment on coal-fired units, as well as new generation resources in order to meet various current federal, state, and local reduction requirements for NO_x and SO_2 emissions. The SCR technology that DEP currently operates on the coal-fired units uses ammonia or urea for NO_x removal and the scrubber technology employed uses crushed limestone for SO_2

removal. SCR equipment is also an integral part of the design of the newer CC facilities in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. The goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emission requirements including the upcoming Mercury and Air Toxics Standards rule. Company witness McGee provides the cost information for DEP's chemical use and forecast.

Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.